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UNITED STATES DISTRICT COURT
CENTRAL DISTRICT OF CALIFORNIA

KEITH ANDREWS, an individual, TIFFANI ANDREWS, an individual, BACIU FAMILY LLC, a California limited liability company, ROBERT BOYDSTON, an individual, CAPTAIN JACK'S SANTA BARBARA TOURS, LLC, a California limited liability company, MORGAN CASTAGNOLA, an individual, THE EAGLE FLEET, LLC, a California limited liability company, ZACHARY FRAZIER, an individual, MIKE GANDALL, an individual, ALEXANDRA B. GEREMIA, as Trustee for the Alexandra Geremia Family Trust dated 8/5/1998, JIM GUELKER, an individual, JACQUES HABRA, an individual, ISURF, LLC, a California limited liability company, MARK

Case No. 2:15-cv-04113-PSG-JEM

[Consolidated with Case Nos. 2:15-CV- 04573 PSG (JEMx), 2:15-CV-4759 PSG (JEMx), 2:15-CV-4989 PSG (JEMx), 2:15-CV-05118 PSG (JEMx), 2:15-CV- 07051- PSG (JEMx)]

DECLARATION OF ROYCE DON DEAVER IN SUPPORT OF PLAINTIFFS' MOTION FOR CLASS CERTIFICATION

Date: November 7, 2016
Time: 1:30 p.m.
Courtroom: Hon. Philip S. Gutierrez

KIRKHART, an individual, MARY KIRKHART, an individual, RICHARD LILYGREN, an individual, HWA HONG MUH, an individual, OCEAN ANGEL IV, LLC, a California limited liability company, PACIFIC RIM FISHERIES, INC., a California corporation, SARAH RATHBONE, an individual, COMMUNITY SEAFOOD LLC, a California limited liability company, SANTA BARBARA UNI, INC., a California corporation, SOUTHERN CAL SEAFOOD, INC., a California corporation, TRACTIDE MARINE CORP., a California corporation, WEI INTERNATIONAL TRADING INC., a California corporation and STEPHEN WILSON, an individual, individually and on behalf of others similarly situated,

Plaintiffs,

v.

PLAINS ALL AMERICAN PIPELINE, L.P., a Delaware limited partnership, PLAINS PIPELINE, L.P., a Texas limited partnership, and JOHN DOES 1 through 10,

Defendants.

I, ROYCE DON DEAVER, hereby declare:

1. I am the President, co-owner, and engineer of DEATECH Consulting Company, an oil and gas pipeline consulting company. I am a Licensed Professional Engineer in Texas in the field of mechanical engineering. Plaintiffs hired me in this proceeding to opine on how, if at all, Plains All American's (Plains) management of Lines 901 and 903 contributed to the May 19, 2015 oil spill and whether the corrective actions issued by the Pipeline Hazardous Material Safety Administration (PHMSA) will be sufficient to protect Plaintiffs and the public at large from future harm.

2. The following declaration is based on my decades of experience in the oil pipeline industry as both an employee of a pipeline company and as a consultant and on publicly available information. My analysis is preliminary and subject to my review of additional documents and any other additional pertinent information I rely on in my final report.

3. Based on my analysis to date, and as described in more detail below, it is my opinion that the Line 901 rupture is a direct result of Plains' deficient management and maintenance of the Pipeline. These deficiencies were not single events, isolated, or caused by out-of-the-ordinary conditions. They are indicative of a company that (1) did not devote sufficient resources to protecting the integrity of Lines 901 and 903, (2) ignored red flags, (3) did not abide by governing regulations, and (4) did not comply with pipeline industry compliance documents.

Professional Background

4. I worked for Exxon Pipeline and Exxon affiliates for over 33 years in numerous technical and management positions. Work activities involved consulting within Exxon, on the Trans Alaska Pipeline System, ARAMCO in Saudi Arabia, Exxon pipeline affiliates, and numerous industry committees and work groups. I created DEATECH in 1997, where I provide consulting and expert witness services to pipeline companies and individuals and businesses who will be,

or have been, impacted by pipelines. My work activities at Exxon as a subject matter expert and later at DEATECH specifically included pipeline regulations, pipeline accident analysis, pipeline corrosion control, fracture prevention and control, and in-line pipeline inspection.

5. My compensation for work on this matter is $395/hour for engineering consulting and analyses and $495/hour for testimony.

6. My current CV is attached as Exhibit 1.

<u>Background on the Rupture of Line 901 and Shutdown of Lines 901 and 903</u>

<u>The Rupture of Line 901</u>

7. Line 901 ruptured on May 19, 2015, spilling oil into the surrounding areas, including the ocean. PHMSA issued a 500+ page failure investigation report on the release. *PHMSA Failure Investigation Report Plaines Pipeline, LP, Line 901, Crude Oil Release, May 19, 2015* (Failure Investigation Report). The most salient points from the report, as relevant to my opinions in this declaration, are as follows.

8. Contributory causes to the rupture, included:

a. Ineffective protection against external corrosion of the pipeline.

i. Condition of the pipeline's coating and insulation system fostered an environment that led to external corrosion.

ii. Pipeline's cathodic protection system was not effective in preventing corrosion from occurring beneath the pipeline's coating/insulation system.

b. In-line inspection (ILI) tool and subsequent analysis of ILI data did not accurately characterize the extent and depth of the external corrosion.

c. Lack of timely detection and response to the rupture.

i. Supervisory control and data system (SCADA) did not have safety related alarms established at values sufficient to alert the control room staff of the release at this location.

ii. Control room staff did not detect the abnormal conditions in regards to the release as the abnormal condition occurred.

iii. Pipeline controller restarted Line 901 after the release occurred.

iv. Pipeline's leak detection system lacked instrumentation and associated calculations to monitor line pack along all portions of the pipeline when it was operating or shutdown.

v. Control room staff training lacked formalized and sufficient requirements including emergency shutdown and leak detection functions such as alarms.

vi. The Plains' oil spill response plan did not identify the culvert near the release site as a spill pathway to the Pacific Ocean.

See Failure Investigation Report at 14-17.

9. The Failure Investigation Report also noted that Plains had previously identified significant and growing corrosion at the Line 901 leak site in 2007, 2012, and 2015 during in line inspections. Based on the level of corrosion, Plains should have excavated and inspected this section of the pipeline before the May 19, 2015 failure. Failure Investigation Report, Appendix G at 22, Table 7 & Figure 17.

<u>Plains Operating Events</u>

10. The causes of the rupture and extent of the release were due to operator errors, including:

a. While a Plains' technician was removing a motor from a non-operating pump unit at Sisquoc Station, the operating pump unit was shut down causing a rise in pressure at Las Flores.

b. The pressure at Las Flores rose from 575 psig to 696 psig due to a surge pressure.

c. The controller shutdown the pump at Las Flores and the pressure remained at 677 psig.

d. About four (4) minutes later at 10:55 a.m., the pump was restarted at Las Flores causing a rise in pressure to 721 psig. Then the pressure suddenly dropped to 199 psig with a higher flow rate of 2042 BPH.

e. The leak detection system did not indicate a release had occurred with a low pressure alarm until 10:58 a.m., three (3) minutes later. However, the Plains' controller did not recognize this as an abnormal condition and failed to take action as required by governing regulations.

f. The accident report indicated the release began at 10:57 a.m., but the pipeline was not shut down until 11:30 a.m.

See Failure Investigation Report at 6, 15-16, Appendix B.

11. Plains' own report of the incident also demonstrated that Plains had not implemented some of the governing safety regulations. The safety regulations that pipeline operators must abide by are codified in the Code of Federal Regulations at 49 CFR Part 195. Section 195.260(c) specifically requires, and has required since before Lines 901 and 903 were constructed, that valves "must be installed" on "each mainline at locations . . . that will minimize danger or pollution from accidental hazardous liquid discharge, as appropriate for the terrain. . . ." But Plains indicated in its report that the valves on Line 901 were 56,752 feet (10.75 miles) apart, meaning that there were no block valves between Las Flores and Gaviota despite a terrain that, in my experience, pipeline operators and regulators would consider to be a prime location for requiring valves.

12. The conclusion from the above is that the causes were not single mistakes, but systematic problems with how Plains failed to properly maintain the pipeline and train its employees.

The Shutdown of Lines 901 and 903

13. Based on initial investigations of Lines 901 and 903 subsequent to the rupture, PHMSA identified a number of concerns related to the extent of corrosion, unresolved inconsistencies related to inspection results, and the insulation and shrink wrap used on the lines. The external coatings and insulation on Lines 901 and 903 prevent cathodic protection from preventing external corrosion. PHMSA therefore ordered Plains to shutdown both lines until certain corrective actions were taken. As described below, the corrective actions are not likely to protect Plaintiffs and the public at large from future harm.

THE RUPTURE OF LINES 901 RESULTED FROM DECADES OF DEFICIENT MANAGEMENT

Lines 901 and 903 Were Not Properly Coated Despite Industry Knowledge that Flaws in Insulation Would Promote Corrosion

14. Plains' Lines 901 and 903 were constructed in the late 1980s and placed in crude oil service in 1992 and 1991 respectively. The problems with corrosion of buried insulated pipelines were well known in the industry when the pipelines were constructed. A number of publications dating back to 1986 indicate external corrosion problems with buried thermally insulated pipeline, like that used for Lines 901 and 903. *See* NACE Report No. 24156, 2006 edition at 8 (compiling publications). The report compiling these publications was attached to PHMSA's investigation into the rupture. Failure Investigation Report, Appendix O.

15. The pipelines transported dense, high viscosity crude oil that was heated to reduce its viscosity for more ease of transportation. The pipelines were insulated with urethane to maintain the elevated higher temperatures. However, the urethane insulation also electrically insulated the buried pipeline from the cathodic

protection electrical current needed to prohibit or mitigate external corrosion of the pipeline in areas where the coating failed or was damaged. No external protective coating is 100% effective by itself during the life of a pipeline. Effective cathodic protection is therefore essential.

16. However, none of the original All American Pipeline from Las Flores to Bakersfield can be cathodically protected due to the presence of urethane insulation and the polyethylene coating. Flaws in the insulation will allow moisture to reach the area under the insulation to create corrosion cells where the coating is missing or disbonded. The high operating temperatures weaken coatings leading to disbondment from the pipe surface. The pipe joints were coated with polyethylene, an electrical insulator that was well known to cause shielding to prevent cathodic protection electricity from reaching the pipeline and protecting it from corrosion.

Plains Did Not Properly Assess Lines 901 and 903 for Purposes of Determining Maintenance Requirements

17. In late 2000, PHMSA adopted new regulations requiring pipeline operators to develop Integrity Management Plans (IMP) for pipelines in high consequence areas such as Lines 901 and 903. The goals of the IMPs were, in part, to accelerate the integrity assessment of pipelines in high consequence areas, improve integrity management systems, and provide increased public assurance in pipeline safety.

18. Pipeline companies had to identify pipeline segments that were in high consequence areas, perform a baseline assessments of those segments, perform regular follow-up assessments, and incorporate all the information learned from the assessments into their management of the pipelines (including operating parameters, maintenance schedules, and timing of follow-up assessments). Plains had to assess at least 50% of such segments, beginning with the highest risk pipe – determined in part by material, manufacturing information, coating type, and cathodic protection history – by September 30, 2004. It had to complete its entire

baseline assessment of all such segments by March 31, 2008. Plains, however, did not complete its baseline assessment of Line 901 until June 21, 2015, almost 11 years after it should have been completed and about a month after the May19, 2015 oil spill from Line 901. *See* Failure Investigation Report at 8.[1]

19. Plains' initial or baseline integrity assessment process was supposed to cover several steps that would have, if properly performed and analyzed, identified issues related to the causes of the spill. These steps include:

a. An information analysis that includes and integrates "all available information" of the entire pipeline.

b. A risk analysis of the pipeline on "all risk factors" for determining the type(s) of integrity test or ILI to be performed.

c. Pipeline segments are to be ranked based on the risk scores using all available information.

d. The priorities and timing to complete the integrity management activities are to be based on the risk scoring.

e. After the tests and/or inspections are performed, the operator must analyze the testing and inspection results to determine if the baseline tests and/or inspections met specified requirements. The operator must excavate numerous areas along the pipeline to determine adequacy of the tests and/or inspections and compliance with stated requirements to detect and define the characteristics of all potentially adverse integrity and safety related conditions.

f. If the integrity assessment did not meet Plains stated requirements, another integrity assessment test must be conducted.

[1] As described below, I have not located publicly available information that would allow me to make similar analyses for Line 903.

g. All the testing and inspection data must be analyzed to determine through an integrity analysis, the "fitness for service" of each condition found during the testing and inspections.

h. Baseline integrity assessment activities are to be evaluated to determine the adequacy of the overall integrity assessment and to define future activities to monitor the pipeline's integrity. The timing of the next integrity assessment and/or imperfections should be determined from all available data.

i. The need for additional preventative and mitigation activities should also be analyzed during the baseline and subsequent integrity reassessments.

20. A key aspect of the IMP process is its iterative and analytical repeating nature: develop a procedure, implement the procedure, test the procedure, make necessary changes, test the updated procedure, and implement the new procedures if they address the concerns. This is typical for PHMSA procedures. As described in more detail below, PHMSA develops performance-based, rather than prescriptive, procedures and relies on pipeline operators to implement the procedures in a way that achieves the desired performance objectives. Plains did not, however, adopt this iterative evaluation process and did not otherwise properly implement the IMP.

21. For instance, Lines 901 and 903 along with any other buried thermally insulated pipelines should have been in the highest risk score category but Plains did not place them in this category. With proper risk scores, Lines 901 and 903 also would have required additional preventative and mitigative measures to address pipeline safety and environmental protection that would have included improvements in the areas of: (a) leak detection, (b) corrosion prevention, (c) mechanical damage prevention, (f) emergency response, (g) emergency shutdown

procedures, (h) additional block valves, and (i) remote control or automatic closing valves.

Plains Did Not Properly Perform Its Integrity Assessment

22. Plains first began its baseline assessment of Line 901 in 2007. The 2007 assessment identified 4,005 metal loss areas in the 10.7 miles of pipe in Line 901 between Las Flores and Gaviota, which impacted 15.5% of the 1,577 joints in Line 901. 385 of those areas were more problematic clusters of numerous corrosion pits that joined to form larger metal loss areas. These metal clusters were reported to be up to 44.2 inches long and up to 36.5 inches wide. Over half of the metal loss areas were in the first half mile where the pipeline temperatures were highest, and many were close enough to affect each other or to interact to diminish the strength of the corroded pipe.

23. Despite having identified more than 2,000 metal loss anomalies in the first half mile of the pipeline, Plains never excavated and inspected the first 1.79 miles out of Las Flores. In 2015, it did not even include the first 1.79 miles in the follow-up in-line-inspection report. The metal loss areas in Line 901 did not receive a complete integrity assessment in the eight years between the initial assessment and the rupture.

24. Plains also did not account for limitations in the methods used to estimate the strength of corroded pipe. The In-Line Inspection (ILI) tool was designed to identify and estimate individual instances of corrosion, but not corrosion clusters. Because Plains relied solely on methods that were not appropriate for corrosion clusters, many of the metal loss areas were misanalysed and treated as if the corroded pipe was stronger than it actually was. Rather than just relying on the ILI tool, all or at least the vast majority of the metal loss clusters should have been excavated to determine the actual remaining wall thickness as required in 49 CFR 195.585 and 195.587. Many of these metal loss clusters should have been classified as “general corrosion” and evaluated for remedial action based

on the "actual remaining wall thickness" as required in 49 CFR Part 195. This type of comprehensive excavation, inspection, and reanalysis is what is expected of pipeline operators and is the minimum necessary to ensure the safe operation of the pipelines.

25. Although Plains had identified 4,005 anomalies, it excavated only 13 spots of external corrosion in 2007, only five of which indicated metal loss consistent with metal loss clusters. Even this limited inspection and reanalysis identified problems with Plains' process, which Plains never addressed. Although the differences between ILI estimated and actual depth measurements were not extreme, the differences between ILI estimated and actual length measurements were great, with the assessment tool significantly understating the lengths of metal loss areas.

26. This is significant because the strength of a metal loss area depends on the depth, length, and width of metal loss. Long and/or wide metal loss areas must be considered as "general corrosion" and analyzed as required in Sections 195.585 and 195.587. Many of the metal loss clusters therefore should have been treated as general corrosion, not as single isolated metal loss areas, and subject to remedial actions.

27. Pipeline companies must determine the metal loss detection capability or accuracy of ILI surveys by comparing the actual measurements from excavation digs to the dimensions estimated by the ILI survey. These comparisons are essential to determine whether the survey met requirements specified by Plains for the integrity assessment. If the statistical analysis indicates the survey did not meet specified requirements, the ILI survey should be at least reanalyzed to correct the estimated metal loss dimensions and/or reject the metal loss analysis. Plains did not do either.

28. The information I have relied on under this heading is from Plains' report on its 2007 inspection, which I downloaded from PHMSA's website. *See*

http://phmsa.dot.gov/staticfiles/PHMSA/ERR/FRP/NEW!_~_2007_Plains_All_American_Pipeline_Inline_Inspection_Survey_Report_Las_Flores_to_Gaviota.pdf. I was not able to locate publicly available versions of Plains' reports on its 2012 and 2015 inspections for Line 901, or any of its inspections for Line 903. I will be able to incorporate information from these reports in my future analyses after Plains produces the relevant reports. PHMSA's June 3, 2015 Amendment Number 1 to the Corrective Action Order (CPF No. 5-2015-501H) does indicate that Plains had a number of inconsistent results for its inspections of Line 903 in 2013 and 2014 that it never resolved.

Plains Did Not Properly Perform Its Follow-Up Assessments

29. Section 195.452(j) in 49 CFR Part 195 requires a continual process of evaluating and assessing a pipeline's integrity. After completing the initial baseline integrity assessment in 2007, Plains was required to continue to assess Line 901 at specified intervals and periodically evaluate the integrity of each pipeline segment. The growth of corrosion and other potentially adverse conditions were required to be monitored and analyzed.

30. Plains was required to conduct periodic inspections and evaluations at least every five years and as frequently as needed to assure continued pipeline integrity. The frequency of these evaluations was to be based on the risk factors specific to each pipeline, including the results of prior assessments, such as the 2007 baseline assessment. The integrity assessments not only included the ILI survey, but the evaluations of pipe strength affected by all anomalous conditions found during each ILI survey.

31. The determination of when to perform the next assessment also had to consider the additional corrosion that would continue to occur between assessments. It was well known in the pipeline industry that buried piping not under full cathodic protection will continue to corrode. This corrosion growth

includes depth, length and width of each corroded area, all of which impact the strength of the pipeline.

32. Plains waited the maximum allowable time to perform a second ILI survey and integrity assessment on Line 901. In waiting the maximum time period of five years, Plains failed to consider the inaccuracies in the 2007 ILI survey and thousands of unresolved anomalous conditions in Line 901 and continuing corrosion growth.

Plains Operated Line 901 Beyond Its Reasonable Service Life

33. The growth of metal loss areas identified in the 2007, 2012, and 2015 ILI assessments shows that Plains operated Line 901 beyond its reasonable life due to the extensive and large areas of corrosion. By matching metal loss areas, we can calculate the corrosion growth rates, which can indicate whether the pipeline has reached its end of life. Metal loss anomalies in the three ILI surveys were matched for analysis of the growth in corrosion depth in external metal loss areas in the May 2015 ILI. *See* Final Inspection Report, Appendix G. About 70 to 73 of the external metal loss areas detected by ILI were matched.

34. The external corrosion rates of the 70-73 matched areas were plotted on probability graph paper for the analysis on Figures 6 and 7 of the 2015 ILI report. The mean corrosion rate for 50% of the data was 7.324 mils per year (0.007324 inch per year). The reported standard deviation of the data was reported as 13.41 mils per year. However, about 30% of the data indicated the corroded areas were "healing" themselves, because the corrosion growth was negative, i.e. subsequent ILI surveys indicated the metal loss was diminishing. This is impossible. These 30% of the data should not have been used in the analysis.

35. When the 30% of erroneous data is deleted, the mean for the remaining data is about 11 mils per year at the original 65% point. The approximate adjustments in the data plotted in Figure 7 should be:

Original %	Revised %	Corresponding mils per year
30	0.0	0
40	14.3	3
50	28.6	6
60	42.9	9
65	50	11
70	57.2	14
80	71.5	19
90	85.7	26
95	92.9	31
-	95.0	33
99.9	99.9	50

36. As shown above, the corrosion growth rate was about 33 mils (0.033 inch) per year.

37. To confirm my analysis, I also calculated the growth rate at a specified confidence level of 95%:

$$c = c_m + c_{sd} \times C_f$$

where:

c = corrosion growth rate, mils per year;

c_m = mean corrosion rate, mils per year;

c_{sd} = standard deviation of corrosion rates, mils per year; and

C_f = single sided uncertainty conversion factor.

38. For this analysis, c_m = 11 mils per year and c_{sd} = 13.41 mils per year. The single sided uncertainty factor for a 95% confidence level is 1.645. The risk weighted corrosion rate is 33 mils per year (0.033 inch per year).

39. This calculation confirms a corrosion rate of at least 33 mils per year for continual assessment of Line 901 between integrity assessments. By way of comparison, pipelines that have no corrosion control typically corrode at the rate of 10-15 mils per year. A 33 mil/year rate of corrosion, combined with the known extent of corrosion on Line 901, indicates that Line 901 has extremely corrosive conditions and has reached the end of its service life, especially in a high consequence area where greater service reliability is required.

40. Because Line 903 is constructed of similar materials, has similar coatings, is insulated in a similar manner, runs through similar soils, and transports the same type of product, I expect, based on my professional experience, that Line 903 is also at or near the end of its reasonable service life.

Plains Has a Poor Safety Performance Record

41. In 2011, PHMSA ranked the safety performance of 147 gas transmission and petroleum pipeline operators. Plains' rankings were poor:

a. Number of regulated miles, 41 from the highest.
b. Number of incidents, 11 from the highest (or worst).
c. Number of incidents per mile, 6 from the highest. Plains Marketing, LP ranked second from the worst.
d. Number of inspections, 29 from the highest.
e. Number of enforcement actions, 19 from the highest.

Plains Has a History of Shirking Its Regulatory Reporting Obligations

42. Sections 195.55 and 195.56 in 49 CFR Part 195 require filing of safety related condition reports on any of the following conditions located 220 yards or less from any building intended for human occupancy, outdoor place of assembly, or onshore location were a release of crude oil could reasonably be expected to

pollute any body of water. This applies to all locations where the safety related condition is not corrected within 10 working days after a representative of the operator discovers the condition.

a. General corrosion that has reduced the wall thickness to less than required for the allowable maximum operating pressure,

b. Localized corrosion pitting to a degree where leakage might result,

c. Any condition that could lead to an imminent hazard and causes a 20% or more reduction in operating pressure of a pipeline, and/or

d. Any material defect or physical damage that impairs the serviceability of a pipeline.

43. In 2007, Plains did not file numerous safety related condition reports on the corrosion found in Line 901 and other buried thermally insulated pipelines.

44. Plains also reduced its maximum operating pressure but failed to report the reduction in a condition report. Safety related condition reports are critical for pipeline safety, because they allow pipeline safety agencies to monitor an operator's actions and to eliminate or otherwise address the safety condition. Plains failed to file safety related condition reports and violated these critical provisions and safeguards set forth in 49 CFR Part 195.

PHMSA's Required Corrective Actions

Are Unlikely to Protect Against Similar Ruptures

45. PHMSA issued a number of Corrective Action Orders (CAOs) to Plains as a result of the May 19, 2015 spill. Plains is supposed to address the issues raised and satisfy the conditions identified in the CAOs before reopening Lines 901 and 903. However, there are a number of reasons to believe that the CAOs will, in my professional opinion, be insufficient to protect Plaintiffs and the public at large from future harm.

46. The CAOs that PHMSA issued to Plains related to Lines 901 and 903 are very general and depend primarily on the initiatives of Plains on how to address

each corrective action. Despite having been authorized, and even required, by Congress to implement comprehensive and specific regulations, PHMSA has not done so. Instead, it has issued general, performance-based regulations. This means that the regulations specify in general terms the safety activities that need to be performed but leave the details of how to perform those activities to the pipeline operator. The specifics of how, and to what extent, the CAOs are completed are usually determined by the pipeline operator. The generalized nature of PHMSA's regulations limits the specificity PHMSA can require in its CAOs.

47. Pipeline operators often do the bare minimum in order to address any required corrective actions. We have already seen this with Plains' response to the CAOs. On May 11, 2016, Plains submitted a "Final Line 901 Remedial Work Plan". This plan was rejected by the U.S. DOT, because the plan did not address all the findings in the pipeline investigation report. PHMSA sometimes pushes pipeline companies to take more comprehensive corrective actions. However, because its regulations are so general and because it lacks sufficient resources, PHMSA often is forced to acquiesce to the pipeline operators' limited approaches.

48. Examples of specific corrections that Plains should be required to implement, but ultimately may not be required by the government to implement, are:

a. Line 901 contains thousands of areas of corrosion, and ILI employed by Plains to date has been ineffective. Any viable correction needs to specify a second type of integrity assessment covered in 49 CFR Part 195 known as a long-term hydrostatic pressure test. Such a test would have to be long-term to allow any temperature differences in the test water and pipeline to stabilize.

b. Plains needs to complete its integrity assessment of the first 1.79 miles of the Line 901 pipeline out of the Las Flores pump station.

c. Finally, Plains needs to install automatic shut-off valves at key locations along Lines 901 and 903 pipeline system.

I declare under penalty of perjury under the laws of the State of Texas that the foregoing is true and correct.

Executed at Montgomery, Texas, this 21 day of August, 2016.

Royce Don Deaver

ROYCE DON DEAVER

CERTIFICATE OF SERVICE

I, Robert J. Nelson, hereby certify that on August 22, 2016, I electronically filed Plaintiffs' **DECLARATION OF ROYCE DON DEAVER IN SUPPORT OF PLAINTIFFS' MOTION FOR CLASS CERTIFICATION** with the Clerk of the United States District Court for the Central District of California using the CM/ECF system, which shall send electronic notification to all counsel of record.

/s/ Robert J. Nelson
Robert J. Nelson